Load-modifier Assumptions
Developed by CEC, CPUC, CAISO, and ARB Staff
In Support of Coordinated Statewide Infrastructure Planning

Document History:

- Originally prepared and finalized by interagency staffs: October 7, 2009
- Modified[1] and approved by CPUC Energy Division for release to RETI: January 13, 2010

Caveats and Context:

- These assumptions were developed in an effort to coordinate infrastructure planning efforts at the CEC, CPUC, CAISO, and ARB. The original impetus was to inform the CAISO's 33% RPS Operational Study. Similar use of these scenarios is being considered by the ARB for its Renewable Electricity Standard rulemaking.
- These are only staff assumptions; they have <u>not</u> been formally adopted or subjected to a decision process at any of the collaborating agencies.
- All load scenarios presume use of the 2009 IEPR Final Demand Forecast.

Table 1: System simulation values, including T&D losses

Decrements from 2020 Supply Needs Based on the 2009 IEPR Final Demand Forecast	
Low Net Load	**High Net Load**
EE: 24,200 GWh CHP: 30,222 GWh 3,608 MW PV/DG: 2,030 GWh 1,260 MW	EE: 0 CHP: 0 PV/DG : 0

<u>RATIONALE:</u>

Low Net Load

- **EE -** The AB32 Scoping plan calls for 32,000 GWh of end-use EE beyond what was included in the 2007 IEPR Demand Forecast. The 24,200 GWh value is a CEC staff estimate of how the increment would be characterized if it were computed from the 2009 IEPR forecast. This figure has been scaled up from **22,305** GWh (at end-use) to include 8.5% line losses for system simulation purposes.
- **CHP** - CEC estimate of Scoping Plan incremental gas-fired CHP in 2020 beyond what is embedded in the 2009 demand forecast.

[1] Modifications were to (1) eliminate the "mid net load" case to bracket the range of renewables net short, while reducing the number of scenarios; (2) eliminate the renewable supply scenarios, because load modifier values within each column were the same for all scenarios (i.e., redundant) and because CPUC plans to update these scenarios; (3) clarify attribution to the interagency coordination effort; and (4) caveat that these assumptions have <u>not</u> been formally adopted by any of the agencies.

- **SB1 PV/DG** - CEC estimate of incremental CSI/DG in 2020, beyond what is embedded in the 2009 demand forecast. (Note: exceeds the Scoping Plan goal.)

High Net Load

- **EE, CHP, and SB1 PV/DG** - Self explanatory (no decrements from 2009 IEPR demand forecast).

OTHER RELEVANT ASSUMPTIONS:

1**. When to Count Losses**. The numbers in the low load scenario show each specific assumption with losses taken from the AB32 Scoping Plan. For the Renewables Net Short calculation the forecast of retail sales should be adjusted by the policy goal without losses. In supply-side simulation modeling losses are included in the algorithm, so the policy goal with losses should be used in a supply side simulation model. The amount of CHP and SB1 PV/DG used on-site avoids losses and reduces retail sales and hence lowers the RPS net short. The amount of CHP which is exported to the grid suffers line losses and does not reduce the RPS obligation (See item 3 below for CHP export ratio).

2. T&D Loss Assumptions The ARB Scoping Plan used an 8.5% loss factor for EE and a 7.7% loss factor for generation programs. We have replicated ARB's Scoping Plan losses in this table.

- **EE:** Scoping Plan without losses = 32,000 GWh. Scoping Plan goal adjusted to 2009 IEPR w/o line loses = 22,305 GWh, which = 24,200 with 8.5% losses.
- **CHP:** Scoping Plan without losses = 30,000 GWh. Scoping Plan goal adjusted to 2009 IEPR without losses = 28,067 GWh, which = 30,222 GWh with 7.7% losses.
- **SB 1 PV/DG**: Scoping Plan without losses = 4,500 GWh. The 2009 IEPR included much of these load reductions, and CEC staff recommended the low net load case assume an additional amount of SB 1 PV/DG without losses = 1,886 GWh, which = 2,030 GWh with 7.7% losses.

3. CHP Split between On-site and Export. Using the logic in the Scoping Plan, the CEC examined a forthcoming publication on 2009 CHP potential which identified a set of programs consistent with the Scoping Plan, that summed to have 50% of the power used on site and 50% exported to the grid.

4. Capacity factors:

- **CHP** - AB 32 Scoping Plan assumes an annual capacity factor of 92.2%. (30,222 GWh /.922 /8,760 hour) * 1000 MW/GW= 3,742 MW Nameplate
- **SB1 PV/DG**: ARB Scoping Plan assumes an annual capacity factor of 18.4% (2,030 GWh/ .184 /8,760 hour) * 1000 MW/GW = 1,259 MW Nameplate

5. MWh conversions are provided for items which are described as MW in the Scoping Plan, but may not correspond to the Scoping Plan value, if the estimate has been updated, depending on the amount of the resource included in the 2009 CEC forecast.

6. **EV Load in 2009 IEPR Forecast.** The 2009 IEPR forecast includes 4,400 GWh of new Electric Vehicle load which, because it is embedded in the forecast itself, is included in both the low and high net load cases.